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2.	Patent application number *(The Patent Office will fill in this part)*	**9915228.2**
3.	Full name, address and postcode of the or of each applicant *(underline all surnames)*	FMC CORPORATION 200 East Randolph Drive Chicago Illinois 60601 U.S.A.
	Patents ADP number *(if you know it)*	46208S001
	If the applicant is a corporate body, give the country/state of its incorporation	Delaware, U.S.A.
4.	Title of the invention	FLOW CONTROL PACKAGE FOR SUBSEA COMPLETIONS
5.	Name of your agent *(if you have one)*	PHILLIPS & LEIGH
	"Address for service" in the United Kingdom to which all correspondence should be sent *(including the postcode)*	7 Staple Inn Holborn London WC1V 7QF
	Patents ADP number *(if you know it)*	0001289001

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Country	Priority application number *(if you know it)*	Date of filing *(day / month / year)*
GB	99 03130.4	11/02/99
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11. I/We request the grant of a patent on the basis of this application.

Signature: Phillips & Leigh

Date: 29th June 1999

12. Name and daytime telephone number of person to contact in the United Kingdom: Martin Hammler 0171 405 0133

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FLOW CONTROL PACKAGE FOR SUBSEA COMPLETIONS

Field of the Invention

This invention relates to apparatus for completion of subsea wells and for controlling fluid flow from and within such wells.

Background of the Invention

Conventionally, subsea completions are carried out from a drilling vessel or platform primarily designed for well drilling and installation of the subsea wellhead. These vessels are highly specialised and expensive to operate. They have usually been used to perform the entire installation sequence of the wellhead and completion.

The key components of known wellhead and completion designs must be installed or removed in a set sequence, as the installation/removal of one component is dependent on the prior installation/removal of another. For example, in a completion including a conventional Christmas tree, removal of the tubing hanger and production tubing requires the prior removal of the tree. With horizontal tree designs, the tubing hanger and its tubing has to be pulled prior to tree removal. This is a time consuming procedure that may be necessary for maintenance or repair of the valves and other equipment incorporated in the subsea completion, including the tree.

A subsea completion will almost always contain service lines extending downhole for controlling, monitoring and powering downhole equipment. The type of equipment and hence the required service lines may vary considerably between completion projects. Hitherto it has been usual for these service lines to exit the well through the side of the wellhead or through a tree attached to the wellhead. This has often necessitated detailed wellhead design changes from one well development to another. During installation of a tubing hanger and an associated tubing string into the wellhead, or during its removal, it may also be desirable to maintain communication with the downhole equipment via the

service lines. Completion designs currently in use allow such communication for up to five service lines. It is desirable to increase the number of service lines available for such communication whilst the tubing string is being run/retrieved.

Summary of the Invention

We have developed wellhead and completion components providing greater flexibility as regards installation and retrieval and which reduce the interdependence between key components during such procedures. We have also developed apparatus for linking downhole service lines to an external control/monitoring/supply point which permits greater standardisation of the wellhead design and allows operation, whilst the tubing hanger is being installed or removed, of downhole equipment attached to the service lines.

In a first aspect, the present invention provides a subsea completion comprising a wellhead from which extends a production fluid conduit; the completion comprising a flow control package removably located externally of the wellhead and containing at least one production flow control valve; an end of the production fluid conduit being releasably coupled to the flow control package by a subsea matable connector external to the wellhead, whereby the flow control package and components within the wellhead respectively may be installed and retrieved independently of each other .

The flow control package performs at least some of the functions of the Christmas tree in prior art completions, in that it provides control of fluid flows from and/or to the well, but it may be assembled from individual components, eliminating the need for large and complex forgings. At the same time this permits great flexibility in design to suit the requirements of a particular completion project. The relocation of flow control components from a Christmas tree forming part of the main wellhead structure to a flow control package releasably coupled externally of the wellhead leads to a design which nevertheless is suitable for use in a wide variety of operating environments. The flow control package may be installed or retrieved independently of completion components

located within the wellhead. Moreover use of a drilling vessel or platform is unnecessary for such installation and retrieval. For example a smaller and less costly to operate diving support vessel can be used, freeing up the drilling vessel for use elsewhere. Casing hangers and completion tubing and a tubing hanger may be consecutively installed in the wellhead without having to remove the BOP stack and install other components. The flow control package may be located at the wellhead, or nearby. Horizontal and conventional Christmas trees have to be positioned on the centre line of the wellhead; the flow control package does not. One conventional or horizontal tree serves one wellhead; a single flow control package according to the invention may serve one or more wellheads.

Preferably a further conduit extends from the wellhead, having one end in communication with a tubing annulus and its other end releasably coupled to the flow control package by a subsea matable connector external to the wellhead. A yet further conduit may extend from the wellhead, having one end communicating with a region above a tubing hanger received within the wellhead, and its other end releasably coupled to the flow control package by a subsea matable connector external to the wellhead. These various conduits thus permit fluid circulation within the completion via the flow control package, equivalent to the circulation possible using a conventional or horizontal Christmas tree. The various connectors may be separate, but preferably are combined to form a unitary hub connector.

When the or each connector is disconnected, a part of the or each connector associated with the wellhead is preferably sealed by a valve, plug or cap.

The tubing hanger may contain an annulus flow passage connected to the tubing annulus conduit and containing a flow control valve of equivalent function to an annulus master valve. Alternatively this valve may be positioned in the tubing annulus conduit or in the wellhead. The tubing hanger may also contain a flow control valve positioned in a production fluid flow passage connected to a tubing string; this valve having a function equivalent to the production master valve of a conventional or horizontal completion.

Alternatively this valve may be positioned in the production fluid conduit or in the wellhead.

The wellhead may be of unitary construction or may comprise a flow spool connected to a separate lower wellhead part and containing the tubing hanger.

The flow control package may contain valves of equivalent function to the production wing valve, annulus wing valve, annulus valve, crossover valve and other flow control valves normally found in a conventional or horizontal subsea Christmas tree. These valves may be separate subassemblies or grouped to form a service valve block and a production flow valve block. Where required, the flow control package may also contain a production choke having an inlet connected to the production wing valve equivalent, and an outlet coupled to a manifold connector or flow line connector.

The flow control package may conveniently be used to house any other equipment needed to control or monitor the production phase of a given well development, such as flow meters, detectors, sensors and chemical injection ports.

In accordance with a second independent aspect of the invention, there is provided a controls cap secured at the top of a wellhead and through which at least one service line is led downhole from outside the wellhead. Where the completion includes an internal tree cap and a tubing hanger below the controls cap, the necessary electrical and hydraulic connections may be led from the controls cap, through the tree cap and tubing hanger and into the tubing annulus. Alternatively, the completion may comprise a tubing hanger located below the controls cap and having a through bore; a first plug being positionable in the through bore for diversion of production fluid into a tubing hanger side outlet; a second plug positionable in the through bore above the first plug; the service line(s) being led from the controls cap, through the tubing hanger and into the tubing annulus. A test port preferably communicates with the space defined between the first and second plugs. Primary and secondary annulus seals may be positioned between the tubing hanger and

the wellhead, with a test port communicating with the void defined between the primary and secondary seals.

During installation and workover/maintenance, when the controls cap is removed, communication with the service lines may be provided via a running tool engaged with the tree cap or tubing hanger. A jumper may be used to connect the controls cap to an external controls interface, situated for example nearby on the seabed, on an adjacent flow manifold, or attached to the wellhead. The physical link between the downhole service lines and the external controls interface can thus be entirely independent of the Christmas tree or flow control package. This differs from prior conventional or horizontal tree designs, where part or all of the service lines link has to be incorporated into the body of the tree. Where desired, the controls interface may be provided by a subsea control module located in the flow control package of a subsea completion according to the first aspect of the invention. This subsea control module may also control elements of the flow control package, such as valves and/or chokes. The controls cap of the invention enables a greater number of service lines to be connected to downhole equipment than has been possible hitherto, which connection can be maintained during installation or removal of the completion.

Further preferred features are described below with reference to the drawings which show illustrative embodiments of the invention.

Brief Description of the Drawings

Fig. 1 is a schematic sectional view of a wellhead forming a first embodiment of the present invention, without the flow control package installed;

Figs. 2a and 2b are similar views of respective alternative embodiments, Fig. 2a being a partial view of the wellhead on a slightly larger scale;

Fig. 3 is a diagrammatic plan view of the flow control package installed on the wellhead of Fig. 1;

Fig. 4 is a side view of the flow control package and wellhead of Fig. 3, in partial section;

Figs. 5 - 10 diagrammatically illustrate various stages of a well drilling and completion operation using the apparatus of the invention;

Fig. 11 shows apparatus of the invention undergoing a workover via a BOP;

Figs. 12a and 12b illustrate two alternative configurations of the apparatus of the invention, undergoing tubing entry workover via a dedicated intervention package and riser;

Fig. 13 shows a modification of the apparatus of Fig. 1, providing disaster recovery in the event of bore damage to the wellhead;

Fig. 14 shows an alternative connector hub which may be used in the present invention;

Fig. 15 is a top view illustrating a flow control package of the invention for use with multiple wells;

Figs. 16-21 show various alternative flow package configurations and arrangements for their connection to the wellhead and a manifold; and

Fig. 22 illustrates comparative installation and workover times for a completion including a flow package and controls cap according to the present invention, and various known completion types.

Description of the Preferred Embodiments

Referring to Fig. 1, there is shown a wellhead 10 supported in an outer housing and a permanent guide base 12, both attached to a conductor casing 14. Casing strings 16 are suspended within the wellhead 10 by hangers 18. A tubing string 20 is suspended from a tubing hanger 22 landed within the wellhead 10. The tubing hanger 22 has a vertical through bore 24 permitting full bore access to the tubing string during workovers. In production mode, production fluid is diverted to a tubing hanger side outlet 26, by a plug 28 in the through bore 24.

The side outlet communicates with a production fluid conduit 30 having one end extending through a side wall 32 of the wellhead 10 and its other end (not shown in Fig. 1) terminating at one part of a subsea matable connector, contained within a connector

hub 34. Chain dotted line 36 indicates the flow path provided by the conduit 30 to the hub 34.

A further conduit 38 extends through the wellhead side wall 32 to a subsea matable connector part in the hub 34, as indicated by chain dotted line 40. The end of conduit 38 within the wellhead communicates with the production annulus via a flow passage 42 formed in the tubing hanger 22. The junction between the conduit 38 and the flow passage 42 is sealed by a pair of sealing elements 44, 46 carried by the tubing hanger 22. The production fluid conduit 30 and the tubing hanger side outlet are similarly sealed together by the sealing element 46 and a further sealing element 48.

A yet further conduit 50 extends through the wellhead side wall 32 from a location above the tubing hanger 22, to a subsea matable connector part in the hub 34, as indicated by the chain dotted line 52. The end of the conduit 50 within the wellhead 10 communicates with a flow passage 54 extending above an internal tree cap 56. For completion installation and workovers, if desired, fluid can be circulated through the flow passage 54 and conduit 50, either with or without the tree cap 56 in place. The tree cap 56 is sealed to the wellhead by a sealing element 58.

Electrical, optical and/or hydraulic service lines 60 for communication with downhole equipment are routed through the tubing hanger 32 and tree cap 56. Communication from there to a workover/production controls system is achieved by installing suitable linking controls connections. As shown in Fig. 1, for production, a controls cap 62 is installed above the tree cap 56, and includes a stab connector 64 which mates with the various lines in the tree cap 56. During workover and installation, a similar stab connector is provided on the various running tools. From the controls cap a suitable jumper extends to a controls/communication interface provided at or near the subsea well, for example a subsea control module in the flow control package.

To provide isolation of the well required as part of the completion operation, the tubing hanger through bore 24 is closable by a remotely operable valve 66. When open,

valve 66 provides unobstructed access to the tubing 20. Likewise, the annulus flow passage 42 in the tubing hanger is closable by a valve 68. The valves 66, 68 may be electrically or hydraulically actuated valves of known kind, e.g. ball valves, and respectively fulfil functions equivalent to the production master valve and annulus master valve in prior completion designs.

When the hub 34 is disconnected from the flow control package as shown in Fig. 1, the flow connection parts in it are sealed by a pressure cap 70.

Fig. 2a shows an alternative embodiment in which the tree cap 56 is replaced by a plug 57 received in the tubing hanger through bore 24, above the plug 28. A test port 29 may be provided, having one end communicating with the space between the plugs 28 and 57, e.g. for monitoring possible leakage past plug 28. The other end of test port 29 (not shown) may terminate at the upper surface of the controls cap 62 or at some other convenient location for connection to an umbilical or monitoring equipment. Optionally, a tubing hanger secondary lockdown mechanism 23 may be provided above the tubing hanger 22. Conduit 50 may be connected to a port or like flow passages schematically illustrated at 51, to provide fluid communication with the wellhead interior above the tubing hanger 22.

As shown in Fig. 2a, the production fluid conduit 30 may pass through the wellhead side wall 32 at a lower level than the annulus conduit 38, rather than vice versa as shown in Fig. 1. A secondary sealing element 45 may be provided above the sealing element 44, with a test port 47 having one end in communication with the void defined between the elements 44, 45, the wellhead 10 and the tubing hanger 22. The other end of the port 47 may be connected to an umbilical or monitoring equipment in similar manner to port 29, e.g. for detecting annulus fluid leakage.

Fig. 2b shows various possible further modifications. Rather than the unitary construction of Fig. 1, the body forming the wellhead 10 comprises a separate flow spool 72 secured to a lower part 74 of the wellhead by a connector 76. The flow spool 72

carries the various conduits 30, 38, 50 and the connector hub 34. It may therefore be secured to existing subsea wellheads using a suitable adapter, converting them for use with the flow control package of the present invention. A separate flow spool is also advantageous in that it may be readily replaced in the event of bore damage, and can be installed after drilling operations are completed, so reducing the risk of damage.

An alternative or additional modification shown in Fig. 2b as compared to Figs. 1 and 2a is that the valves 66, 68 in the tubing hanger are replaced by valves 78, 80 in the production fluid and annulus conduits 30, 38 respectively. These valves may either be located in external pipework attached to the wellhead as shown, or in the wellhead side wall. Relocation of the annulus valve 80 as shown in Fig. 2b or to the wellhead side wall allows the seal 44 of Fig. 1 to be eliminated.

A yet further possible modification shown in Fig. 2b is that the tree cap 62 is of solid construction. The construction shown in Fig. 1 incorporates a plug 134, permitting tubing entry access without removal of the cap, e.g. for lightweight intervention operations.

Figs. 3 and 4 show the flow control package 82 installed around the wellhead 10. As shown, a hub connector 84 lies above and mates with the hub connector 34 of the wellhead after removal of the pressure cap 70. However, many other connector configurations will also be suitable to provide fluid communication between the wellhead and flow control package. Hub connector 84 contains complementary connector parts providing fluid tight couplings with the connector parts of the wellhead hub 34. Production conduit 30 is thereby connected via pipe 85 to a production flow block 86 containing flow control valves, for example a valve functionally equivalent to the production wing valve in a Christmas tree. The hub connectors 34 and 84 likewise interconnect the annulus conduit 38 and the BOP circulation conduit 50 with respective conduits 88 and 90 leading to a service block 92 containing valves having additional service control functions as may be required for a given completion project. For example these valves may have functions equivalent to the annulus wing valve, annulus access

valve and crossover valve in a Christmas tree. The service valve block shown in Fig. 3 contains two such valves. A crossover conduit 94 extends between the service valve block 92 and the production flow block 86. The various valves in the flow control package include associated actuators 96, 98, 100 which are hydraulically powered and/or may have operating shafts 102, 104, 106 coupled to ROV receptacles 108, 110, 112 in ROV panel 114. Production flow is directed from block 86 through a production choke 116 and from there to a flow line or manifold connector 118, coupled to a flowline 119 as shown. The production choke is optional, depending on project requirements.

The flow control package 82 may also include the controls/communication interface in the form of a subsea control module 120 containing equipment for monitoring and controlling the operation of downhole equipment such as a DHSV and pressure and temperature sensors, as well as for controlling the valves 66, 68 or 78, 80 associated with the tubing hanger 22, wellhead 10 or flow spool 72. Module 120 may also control the valves in the flow control package 82 itself, as well as the production choke 116 and any other equipment which may be included in the flow control package for a given completion project. As shown in Fig. 4, a jumper 122 provides the necessary electrical and hydraulic connections between the control module 120 and the control cap 62.

Figs. 5 to 10 illustrate a typical installation sequence for a completion including the wellhead 10 and flow control package 82. As shown in Fig. 5, first the conductor casing and PGB are installed. Next the wellhead is installed with the pressure cap 70 in place on the hub 34. A bore protector 124 is preinstalled in the wellhead 10. As shown in Fig. 6, next a BOP 125 is installed on the wellhead 10 and the casing strings 16 are drilled, run and cemented. The bore protector 124 is then removed and the tubing string 20 and its hanger 22 are run and landed in the wellhead 10 using a running tool 126 (Fig. 7). A service line connection 61 is provided in the running tool 126, which mates with the service lines 60 extending downhole into the tubing annulus, for example strapped to the outside of the tubing. The plug 28 is then set in the tubing hanger 22 and the tree cap installed in the wellhead 10 in the position shown in Fig. 1. (Or the plugs 28, 57 are set in the tubing hanger: Fig. 2a.) The BOP is then removed. The pressure cap 70 can now be

removed, for example using ROV 127, Fig 8. The flow control package 82 is then installed on the wellhead 10 with the hub connectors 34, 84 in mating engagement (see Fig. 10). As shown in Fig. 8, the flow control package may be wire deployed, for example from a DSV, using ROV hooks 128. Alternatively, as shown in Fig. 9, the flow control package 82 may be drill pipe deployed. Control during installation of the flow control package 82 can be achieved by umbilical 129, ROV 127 or other means. Finally, the controls cap 62 and jumper 112 are installed, for example using an ROV, to arrive at the configuration depicted in Fig. 4. The present invention however allows considerable flexibility in the installation sequence. For example, the flow control package can be preconnected to the wellhead; the wellhead and flow package assembly then being landed in the outer housing and PGB 12. Alternatively, the flow package may be separately installed either before or after tubing hanger installation.

Fig. 11 schematically illustrates a workover operation requiring full bore access, conducted using BOP 125. The wellhead 10 projects sufficiently far above the flow control package 82 to allow the BOP 125 to engage the top of the wellhead 10 with the flow control package installed. However, if desired, workover may be carried out without the flow control package in place. Prior to installation of the BOP, the controls cap 62 is removed using an ROV. The tree cap 56 is removed using a landing string run within the BOP to initiate the well entry, and may be installed likewise. The internal configuration of the wellhead with the BOP in place is then similar to that shown in Fig. 7 (tubing hanger installation).

Figs. 12a and 12b illustrate a tubing entry workover ("lightweight intervention"). Fig. 12a shows a dedicated workover apparatus 130 and riser 132 engaging the top of the wellhead 10 with the flow control package 82 still in place. To permit such engagement, the controls cap 62 is again removed. Tubing entry access is gained by removing a plug 134 in the tree cap 56 (Fig. 1), removing plug 28 and opening the valve 66. The resulting configuration is as shown in Fig. 12b, except that in that figure the flow control package 82 is shown removed and the pressure cap 70 installed on the hub 34.

In the event that the bore of the wellhead is damaged and incapable of receiving the tubing hanger, Fig. 13 illustrates use of a flow spool 136, somewhat similar to flow spool 72 in Fig. 2, as an adapter to recover the wellhead. The hub 34 associated with the wellhead 10 is permanently capped and a new hub 138 of the flow spool 136 is used to connect to the flow control package 82 (not fully shown). The flow control package includes a modified flow loop 140 for connection to the manifold/flow line. If the flange connectors of the conduits 30, 38, 50 leak, an isolation sleeve 142 can be installed and sealed in the wellhead, between the casing hangers 18 and the flow spool 136.

Fig. 14 shows an alternative hub 144 for the wellhead 10, including a ROV/diver replaceable section, used to eliminate the risk of losing the well due to hub damage.

Fig. 15 shows a flow control package 149 capable of connection to multiple wells. To that end, it includes a pair of hub connectors 146, 148 for connection to respective wellheads 150 and 152. Again a flowline/manifold connector 118 is provided, through which the production flow is led to a flowline 119 or a manifold.

Although the previously illustrated flow control packages are shown surrounding the wellhead 10 when installed, as shown in Fig. 16 the flow control package 82 could equally well be modified for installation to one side of the wellhead, connected to it using a vertical stab, horizontal stab or a differently orientated connector schematically illustrated as 160. A production flow outlet from the flow control package 82 can be connected via a jumer 166 and connector 168 to a nearby manifold 162, supported on a foundation 164. The horizontal distance between the connectors 160 and 168 may be for example, 10-30 m.

Fig. 17 shows a flow control package 83 positioned to one side of the wellhead 10 and having a hub connector portion 84 that interfaces directly with the wellhead hub connector 34. Flow control package 83 contains a valve block 170, valve actuators 172, a production flow choke 116, and additional production fluid processing equipment 174. Such equipment may comprise for example gas/water separator stages, gas to liquid

conversion plant, pumps and the like, that would ordinarily be positioned further down the production flow stream rather than directly adjacent to the wellhead. Production fluid is led from the flow package 83 via an isolation valve 176, connector 180 and flowline 178.

Fig. 18 shows in plan, and Fig. 19 in elevation, a template installation comprising multiple wells 182 (only two shown). A template 184 supported on a foundation 186 contains and locates the wells 182 and also supports a manifold 188. Multiple flow control packages 190, one associated with each well 182, are supported between hub connectors 192 on each well 182 and further hub connectors 194 on the manifold 188.

Figs. 20 and 21 generally correspond to Figs. 18 and 19 respectively, but show modified flow connections between the wells, flow control packages and manifold. Each well 182 is directly connected to the manifold 188 by a respective hub connector 196. The flow packages 190 are mounted solely on the manifold 188. Respective unitary hub connectors 198 conduct fluid flows in both directions between each flow control package 190 and the manifold. Other flow configurations can readily be envisaged: for example a flow package may serve several wells.

The hub pressure cap or plug and controls cap could be diver installed/removed, or installed/removed by a suitable tooling package. Further variations and modifications of the described embodiments are readily possible, within the scope of the claims.

Finally, Fig. 22 shows estimated times for installation (including well drilling time), Christmas tree workover, tubing workover, light intervention (tubing access) and heavy intervention (full bore access) for a completion including the flow package and controls cap of the invention, in 1400m water depth. For comparison, equivalent times for conventional, tubing head and horizontal completions are also given. The present invention offers reduced installation and tubing workover times and markedly reduced tree workover times compared to the other designs. Light and heavy intervention times are comparable with those for a horizontal completion.

The invention permits greater flexibility in wellhead component manufacture, well completion, workover and maintenance operations, improved resource usage and reduced costs. Preferred embodiments of the wellhead and flow control package of the invention are particularly suitable for deep water applications.

CLAIMS

1. A subsea completion comprising a controls cap secured at the top of a wellhead and through which at least one service line is led downhole from outside the wellhead.

2. A completion as defined in claim 1 comprising an internal tree cap and a tubing hanger located below the controls cap, the service line(s) being led from the controls cap, through the tree cap and tubing hanger and into the tubing annulus.

3. A completion as defined in claim 1 comprising a tubing hanger located below the controls cap and having a through bore; a first plug being positionable in the through bore for diversion of production fluid into a tubing hanger side outlet; a second plug positionable in the through bore above the first plug; the service line(s) being led from the controls cap, through the tubing hanger and into the tubing annulus.

4. A completion as defined in claim 3 comprising a test port communicating with the space defined between the first and second plugs.

5. A completion as defined in any of claims 2-4, wherein communication with the service line(s) is provided via a running tool engaged with the tree cap (where present) or tubing hanger when the controls cap is removed.

6. A completion as defined in any of claims 2-5 comprising primary and secondary annulus seals positioned between the tubing hanger and the wellhead; a test port communicating with the void defined between the primary and secondary seals.

7. A completion as defined in any preceding claim wherein a jumper connects the controls cap to an external controls interface.

8. A subsea completion comprising a wellhead from which extends a production fluid conduit; the completion comprising a flow control package removably located

externally of the wellhead and containing at least one production flow control valve; an end of the production fluid conduit being releasably coupled to the flow control package by a subsea matable connector external to the wellhead, whereby the flow control package and components within the wellhead respectively may be installed and retrieved independently of each other .

9. A subsea completion as defined in claim 8 wherein a further conduit extends from the wellhead, having one end in communication with a tubing annulus and its other end releasably coupled to the flow control package by a subsea matable connector external to the wellhead.

10. A subsea completion as defined in claim 8 or 9 wherein a further conduit extends from the wellhead, having one end communicating with a region above a tubing hanger received within the wellhead, and its other end releasably coupled to the flow control package by a subsea matable connector external to the wellhead.

11. A subsea completion as defined in claim 9 or 10 wherein the connectors are combined to form a unitary hub connector.

12. A subsea completion as defined in any of claims 8-11 wherein, when the or each connector is disconnected, a part of the or each connector associated with the wellhead is sealed by a valve, plug or cap.

13. A subsea completion as defined in any of claims 8-12 comprising a tubing hanger containing an annulus flow passage connected to the tubing annulus conduit and containing a flow control valve.

14. A subsea completion as defined in any of claims 8-12, including a flow control valve positioned in the tubing annulus conduit.

15. A subsea completion as defined in any of claims 8-14, comprising a tubing hanger containing a flow control valve positioned in a production fluid flow passage connected to a tubing string.

16. A subsea completion as defined in any of claims 8-14, comprising a flow control valve positioned in the production fluid conduit.

17. A subsea completion as defined in any of claims 8-16 and wherein the wellhead comprises a flow spool connected to a separate lower wellhead part and containing a tubing hanger.

18. A subsea completion as defined in any of claims 8-17 wherein the flow control package contains one or more valves of equivalent function to a production wing valve, annulus wing valve, annulus valve or crossover valve.

19. A subsea completion as defined in claim 18 wherein the valves in the flow control package are formed as separate subassemblies.

20. A subsea completion as defined in claim 18 wherein the valves in the flow control package are grouped to form a service valve block and a production flow valve block.

21. A subsea completion as defined in any of claims 8-20 wherein the flow control package contains a production choke.

22. A subsea completion as defined in any of claims 8-21 wherein the flow control package is supported on a well template.

23. A subsea completion as defined in any of claims 8-21 wherein the flow control package is supported on a manifold.

24. A completion as defined in claim 7 and any of claims 8-23, wherein the controls interface comprises a subsea controls module located in the flow control package.

25. A subsea completion comprising a wellhead and a flow control package substantially as described with reference to or as shown in the drawings.

Abstract

[Fig. 4]

FLOW CONTROL PACKAGE FOR SUBSEA COMPLETIONS

A subsea completion comprises a wellhead 10 having a side wall through which extends a production fluid conduit 30. The completion further comprises a flow control package 82 removably located externally of the wellhead and containing at least one production flow control valve; an end of the production flow conduit 30 being releasably coupled to the flow control package 82 by a subsea matable connector 34, 84. A controls cap may be secured to the top of the wellhead 10, connected to a nearby controls interface by jumpers 122. Service lines are led downhole through the controls cap.

Fig. 1

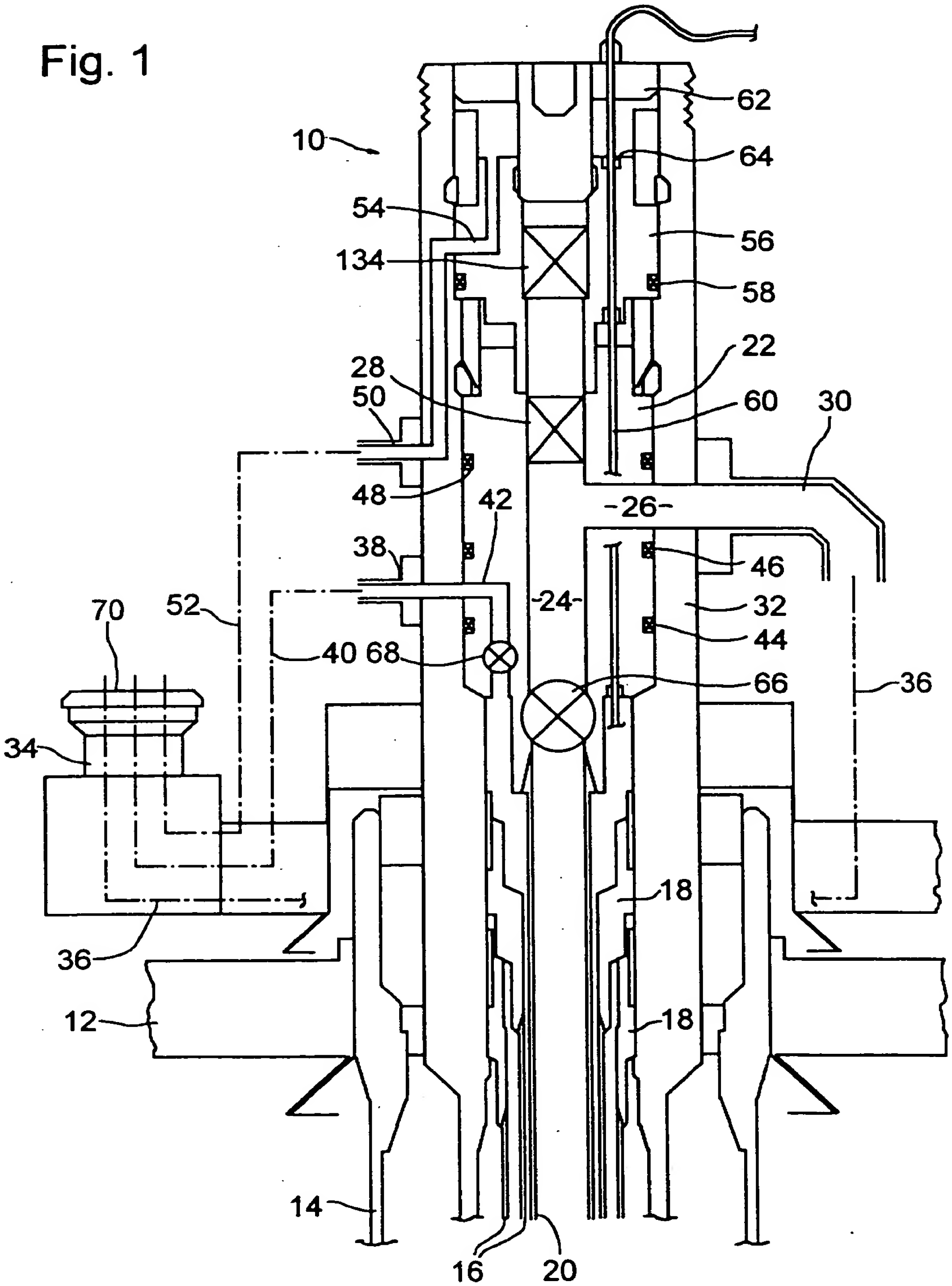

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Fig. 2a

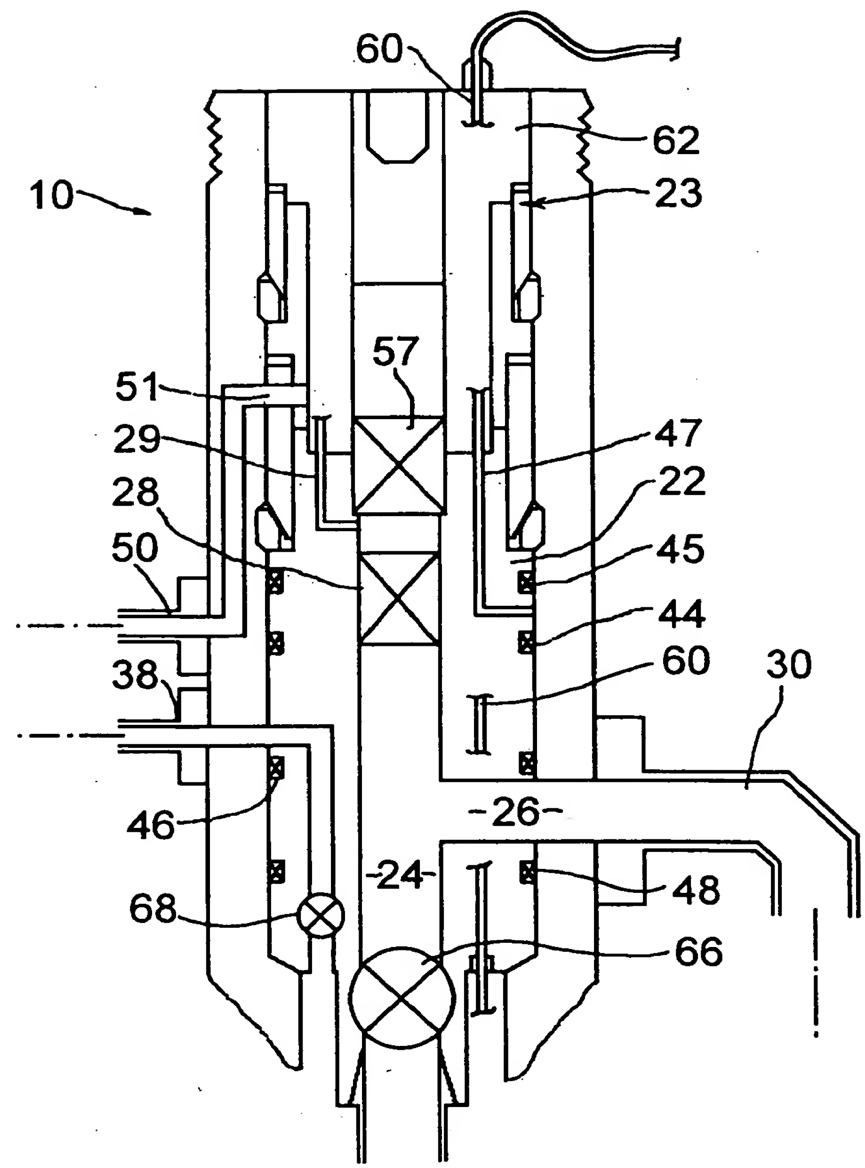
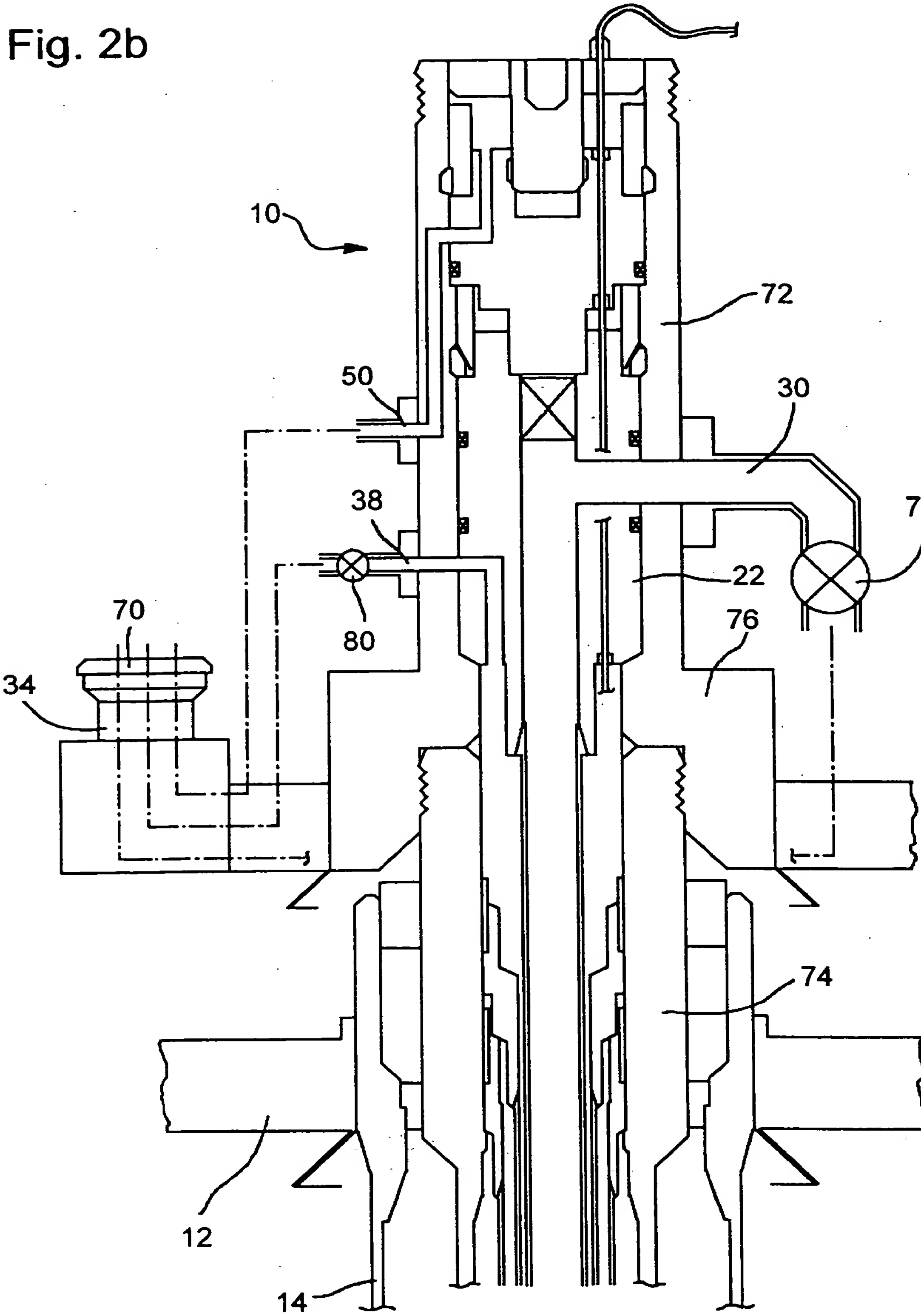


Fig. 2b



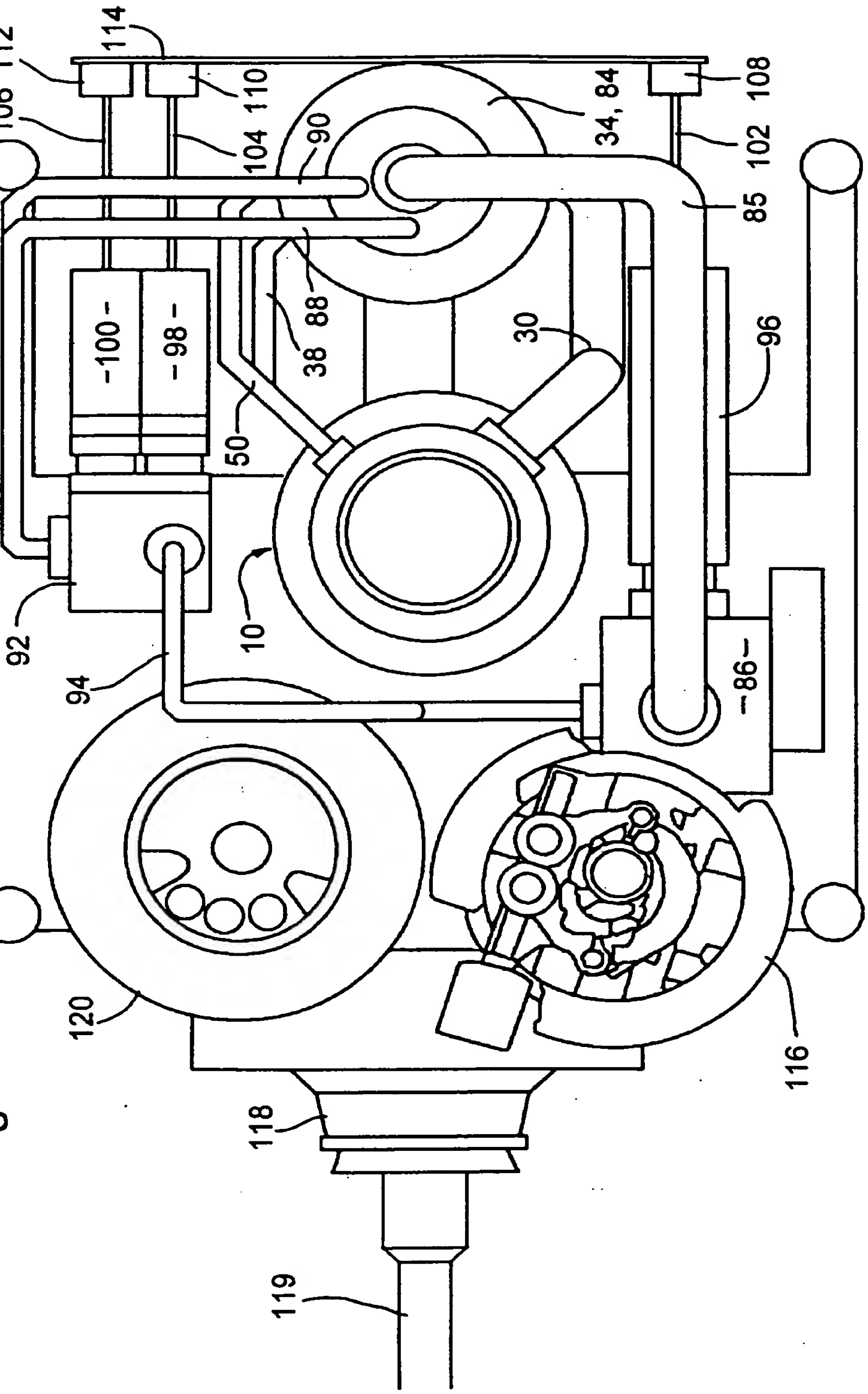

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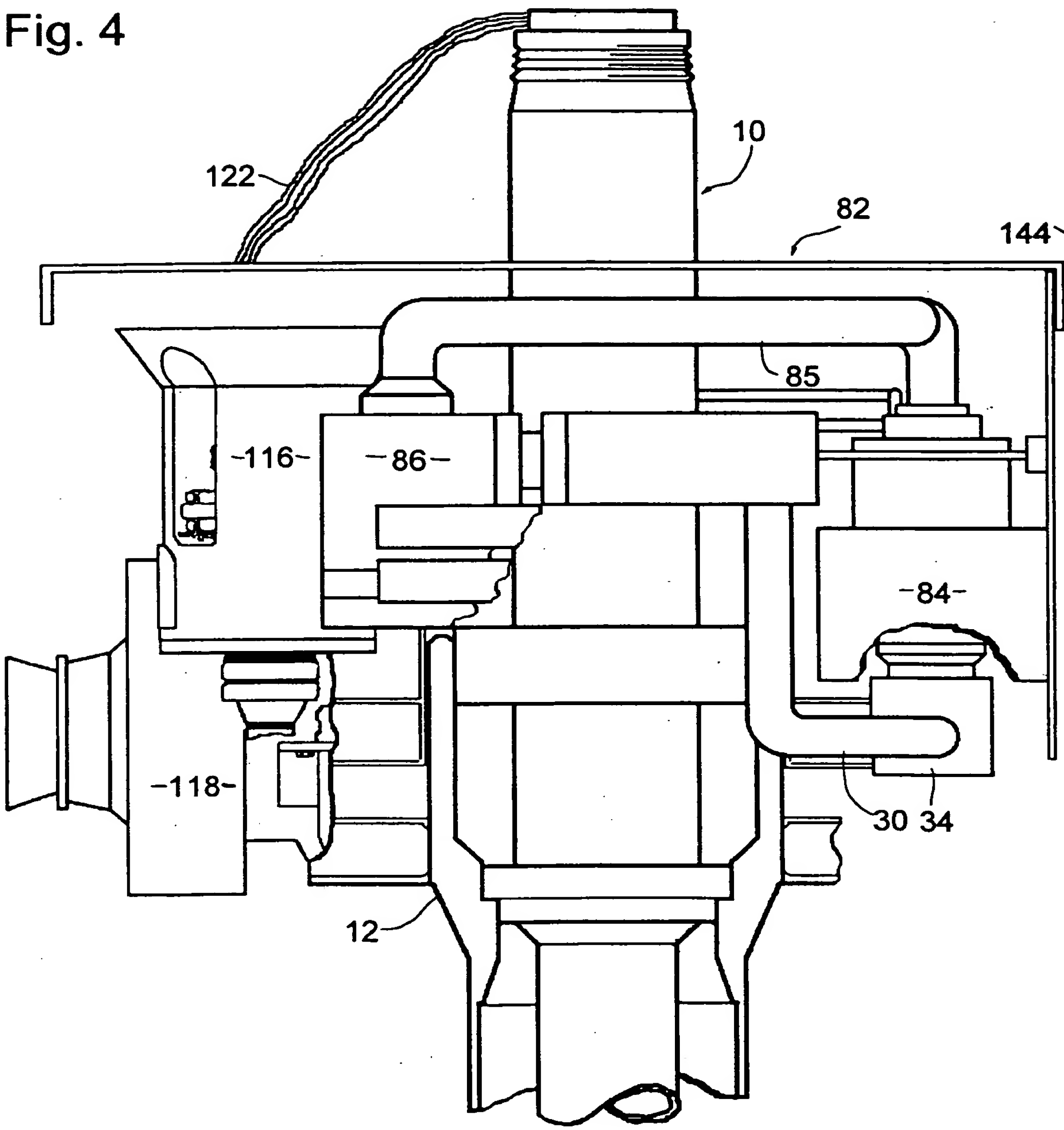
Fig. 3

Fig. 4



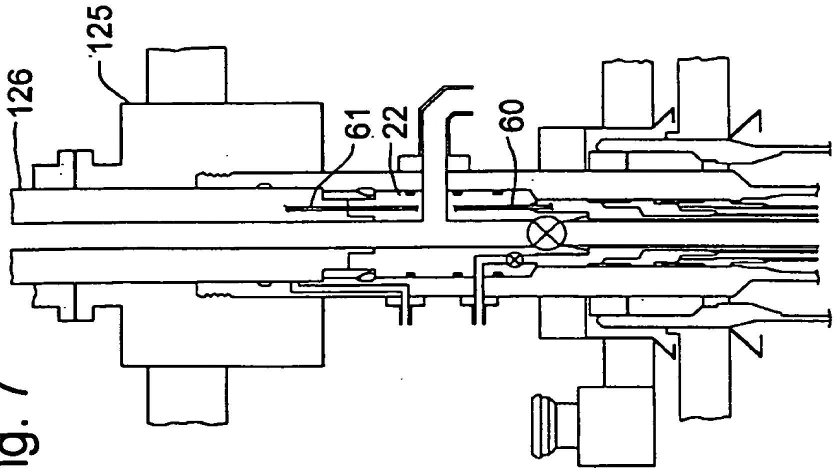


Fig. 7

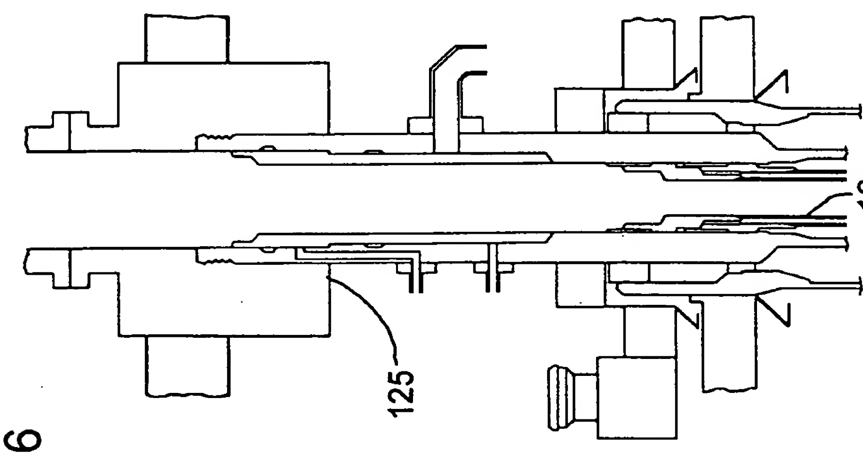


Fig. 6

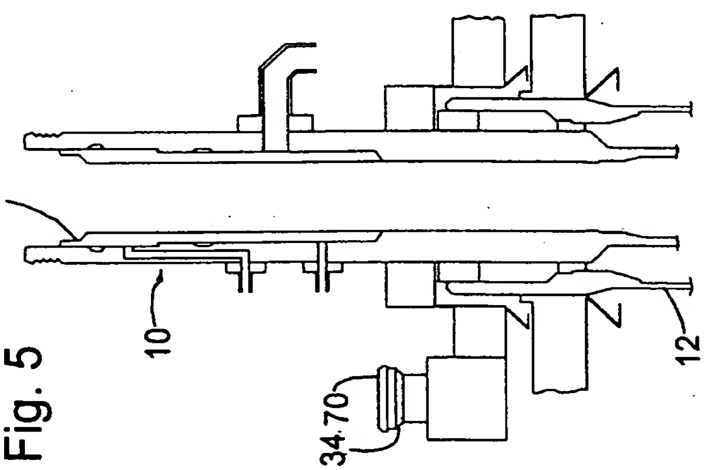


Fig. 5

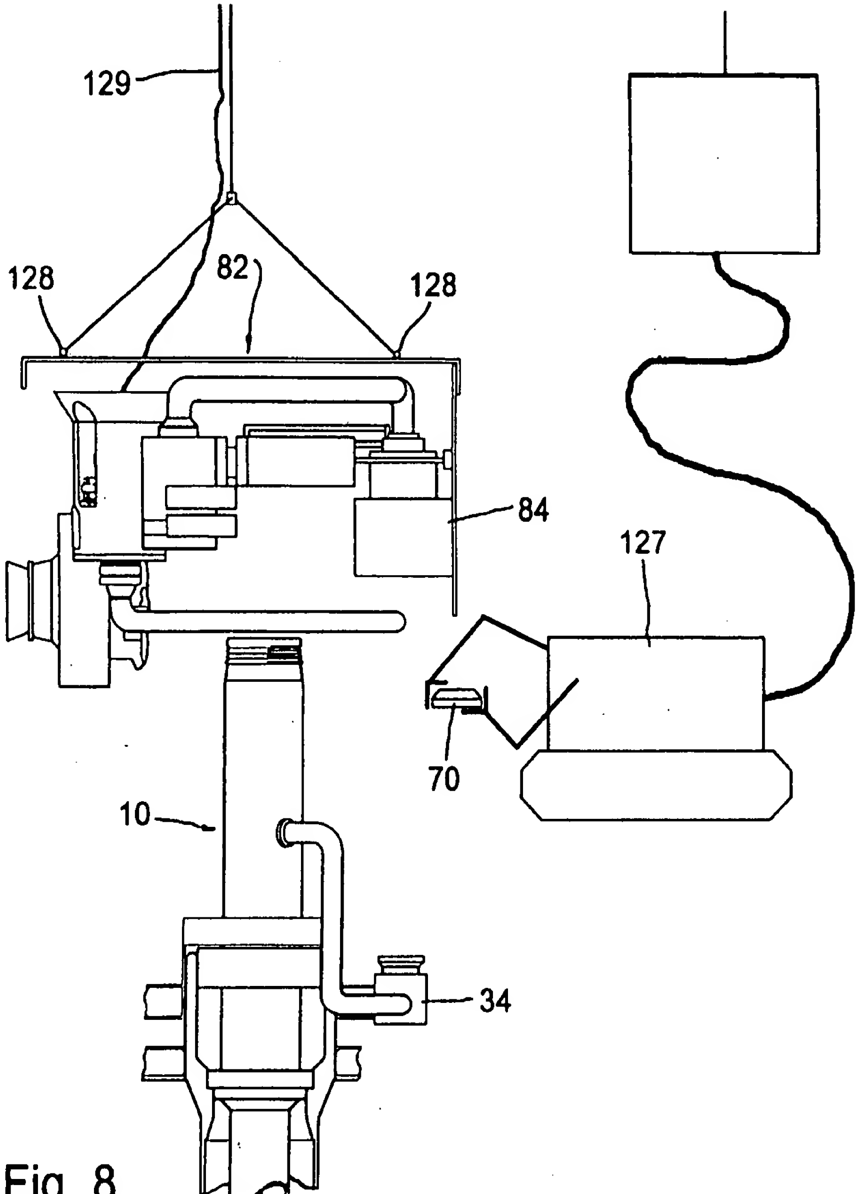


Fig. 8

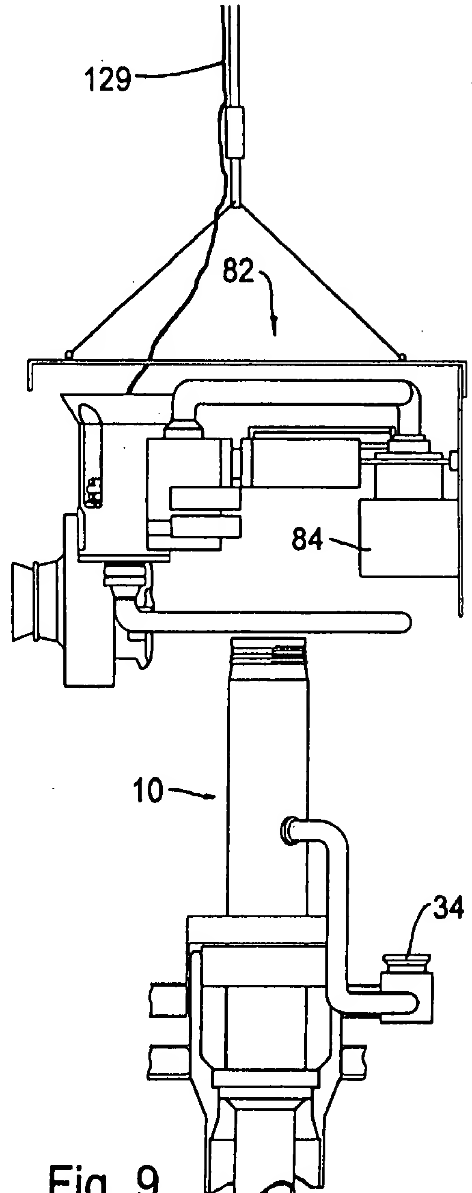


Fig. 9

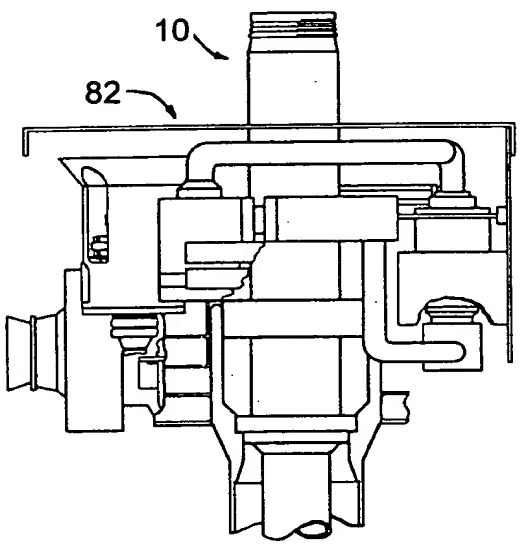


Fig. 10

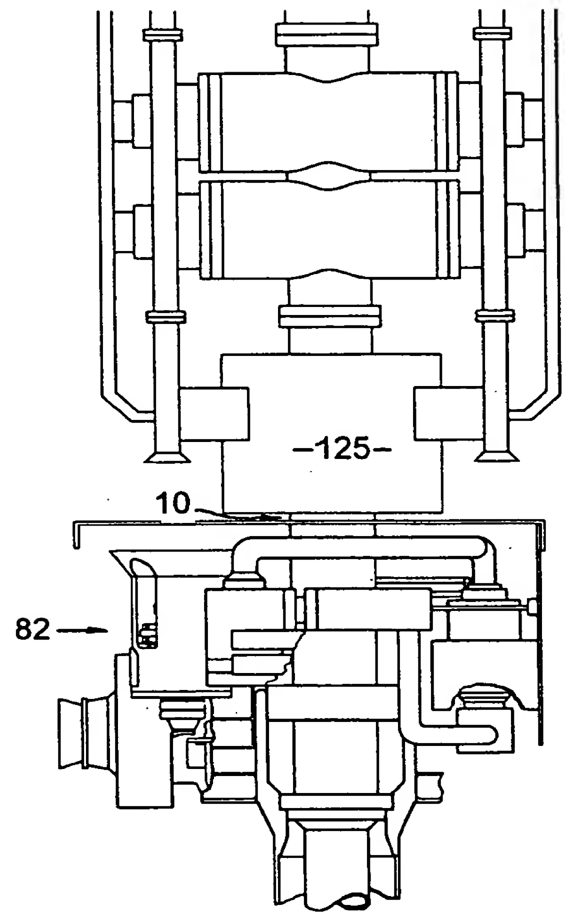


Fig. 11

Fig. 12a

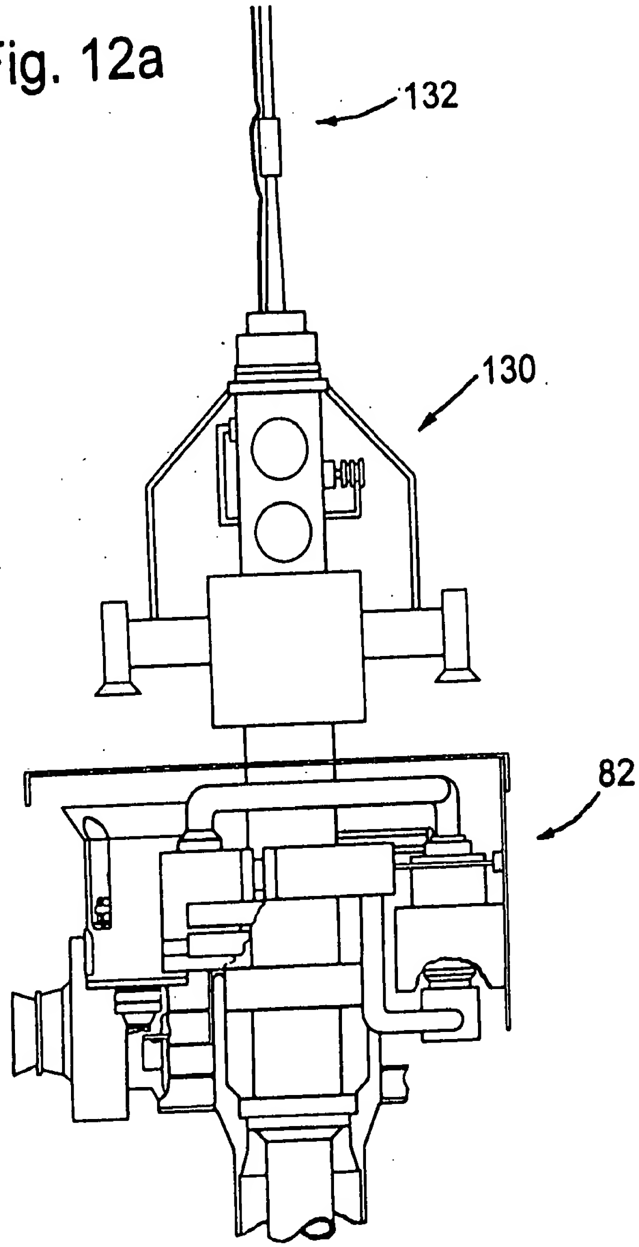


Fig. 12b

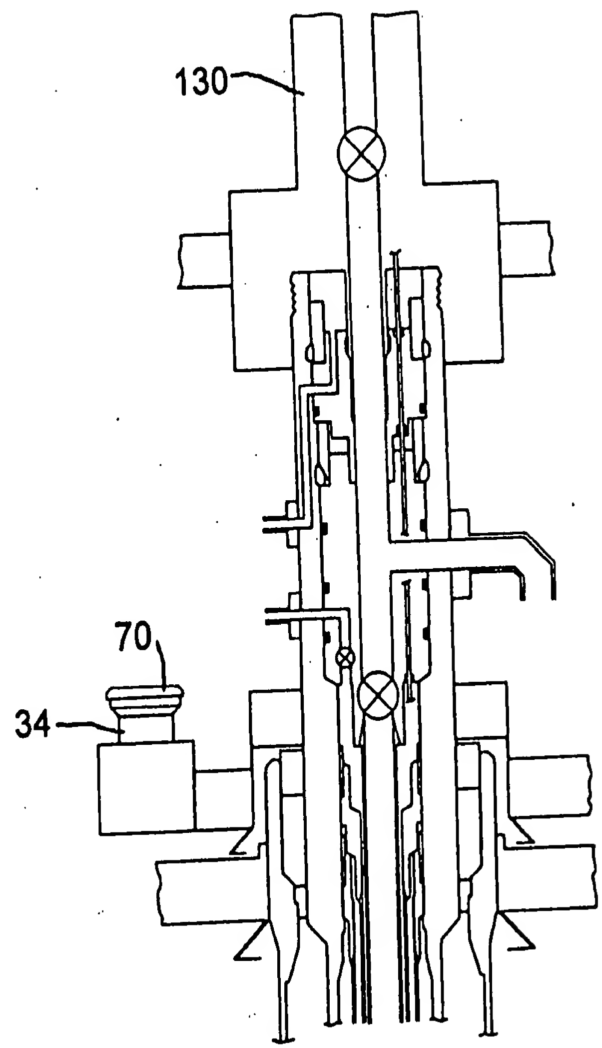


Fig. 13

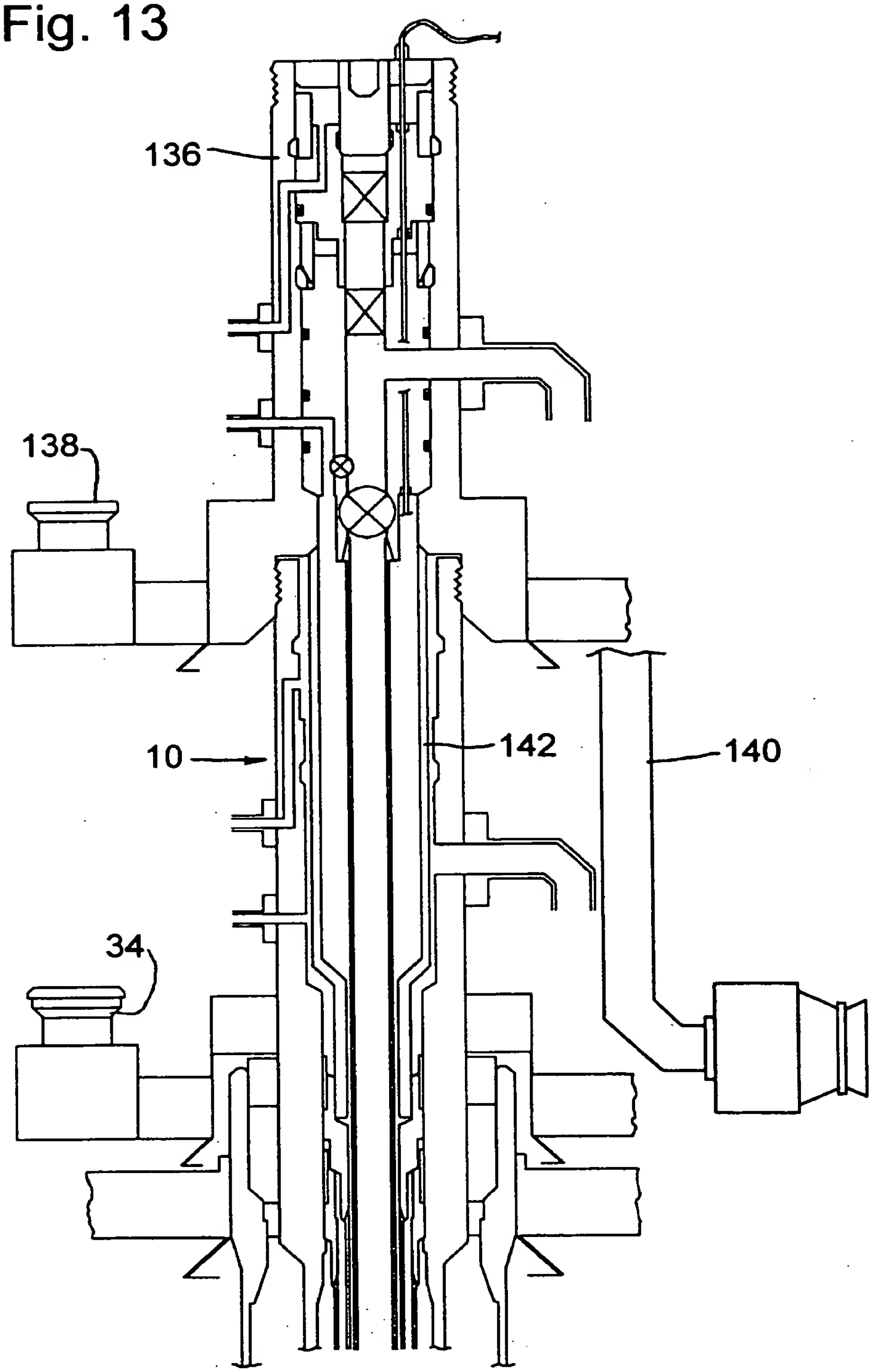


Fig. 14

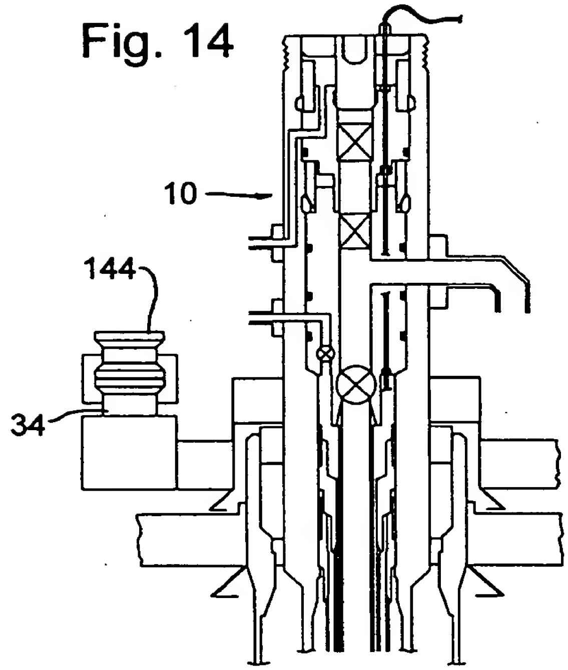
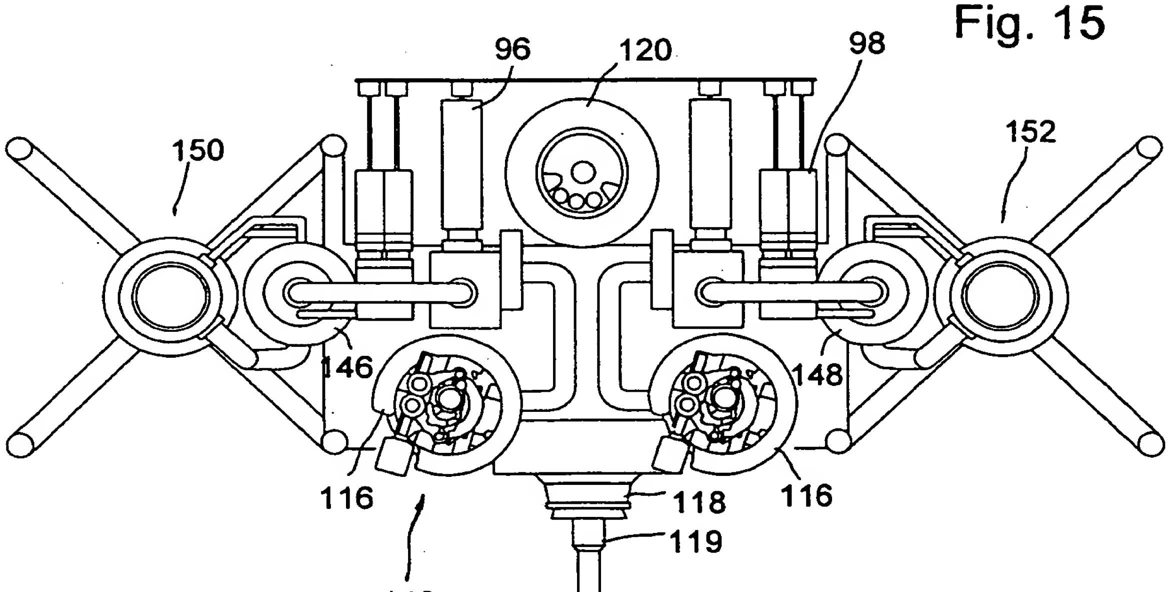


Fig. 15



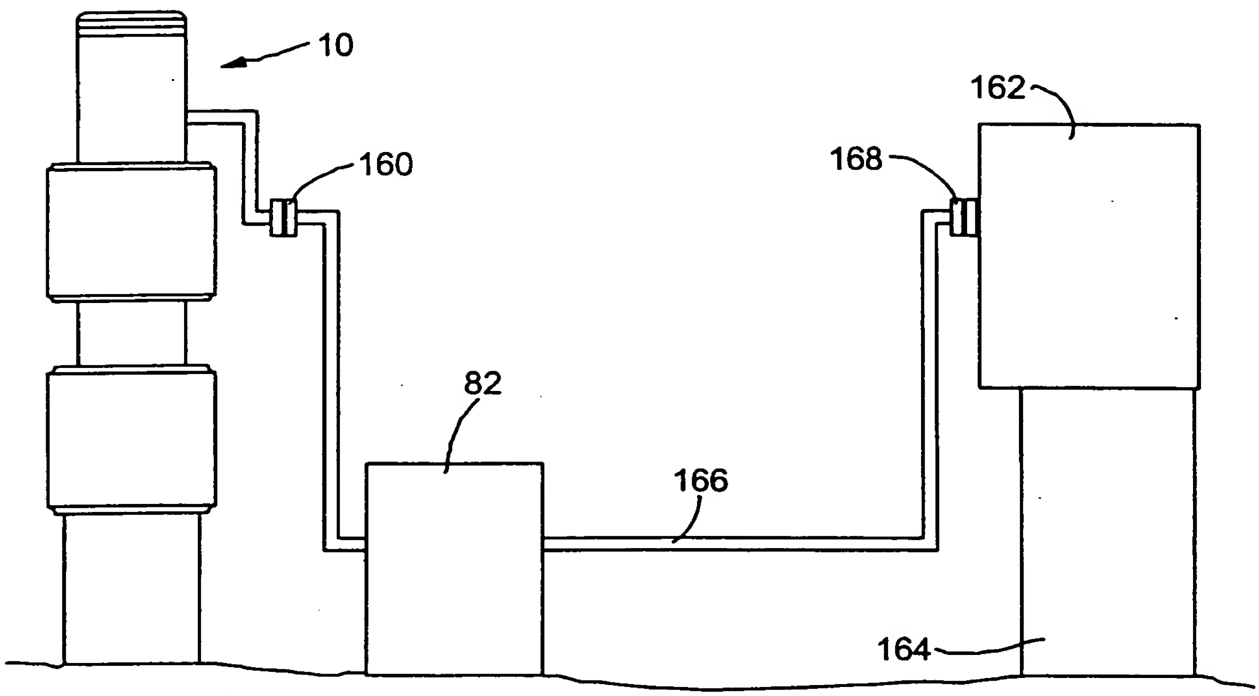


Fig. 16

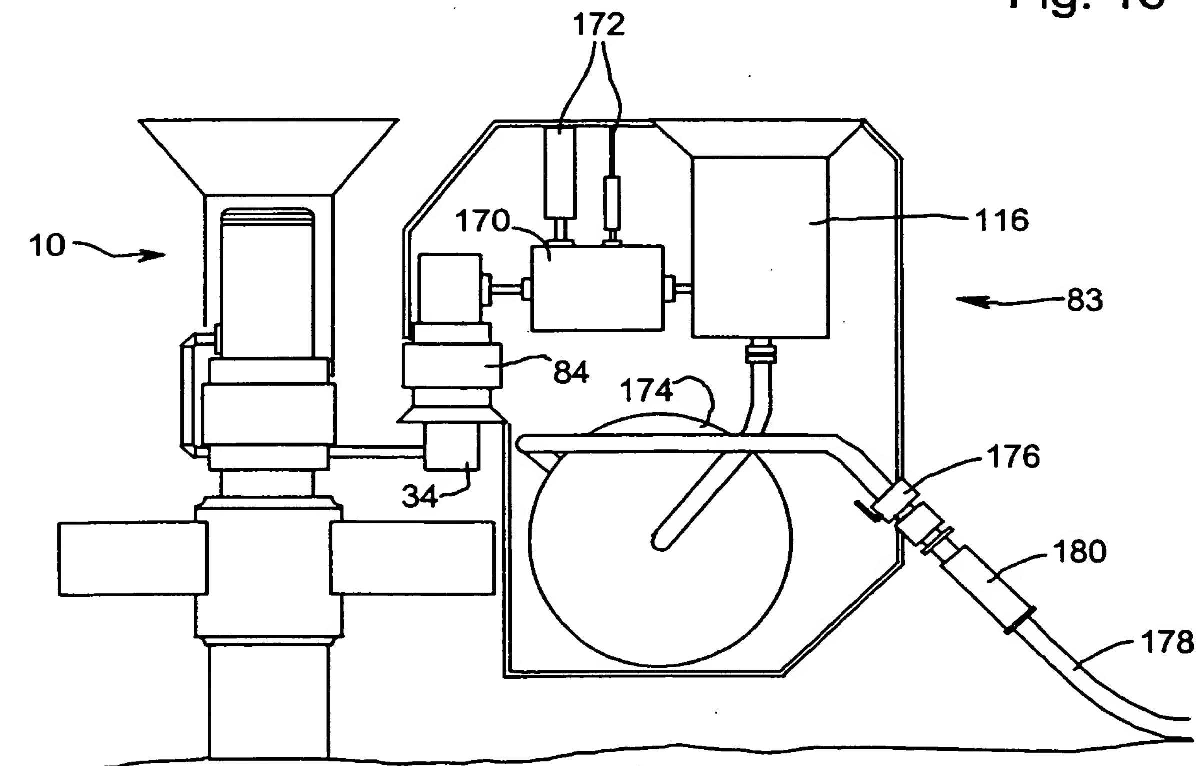


Fig. 17

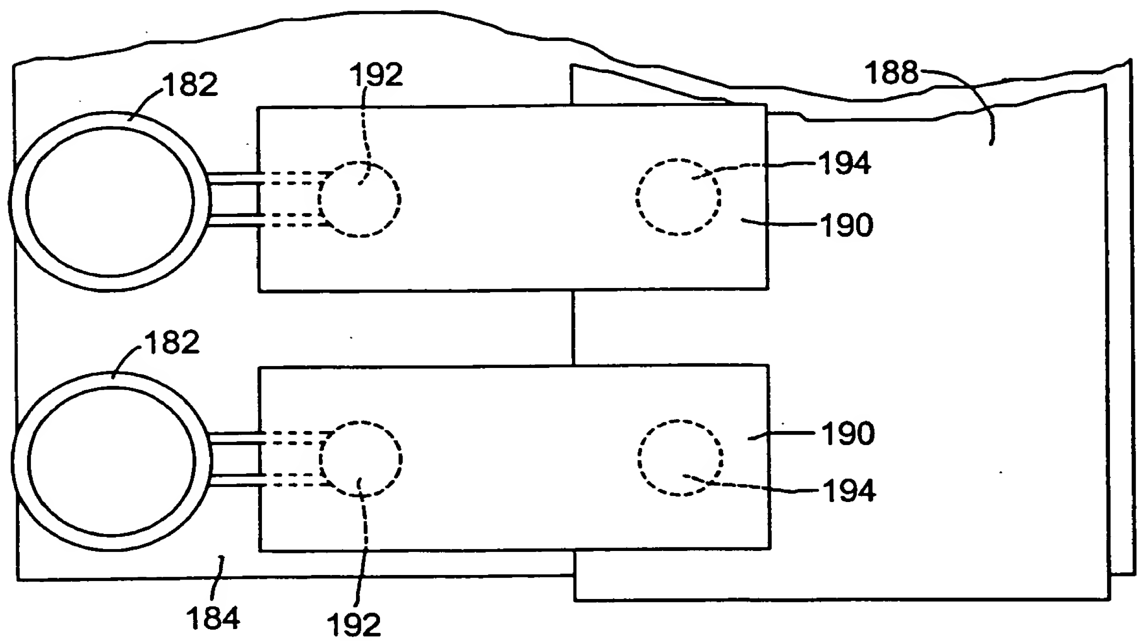

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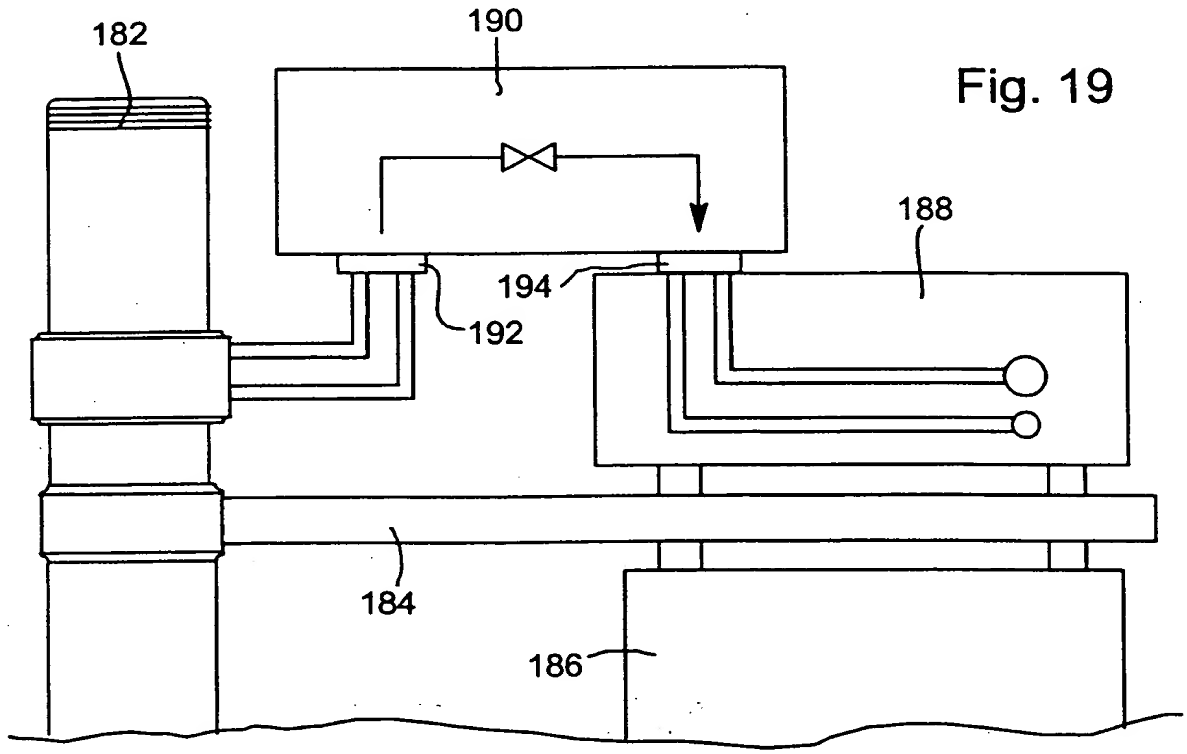
Fig. 18

Fig. 19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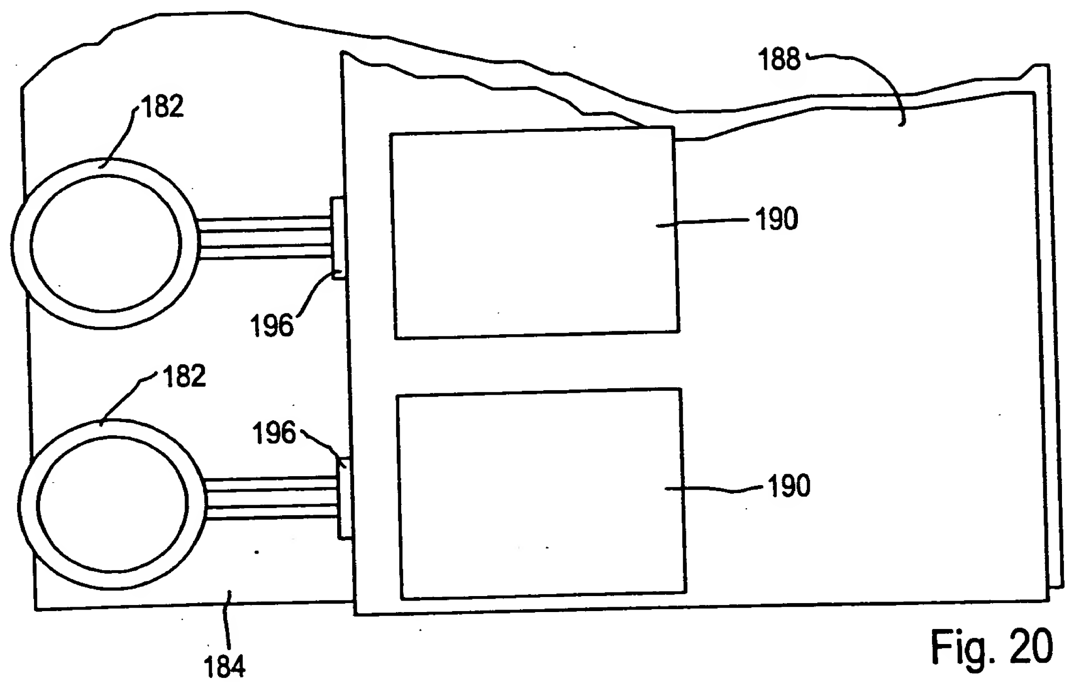


Fig. 20

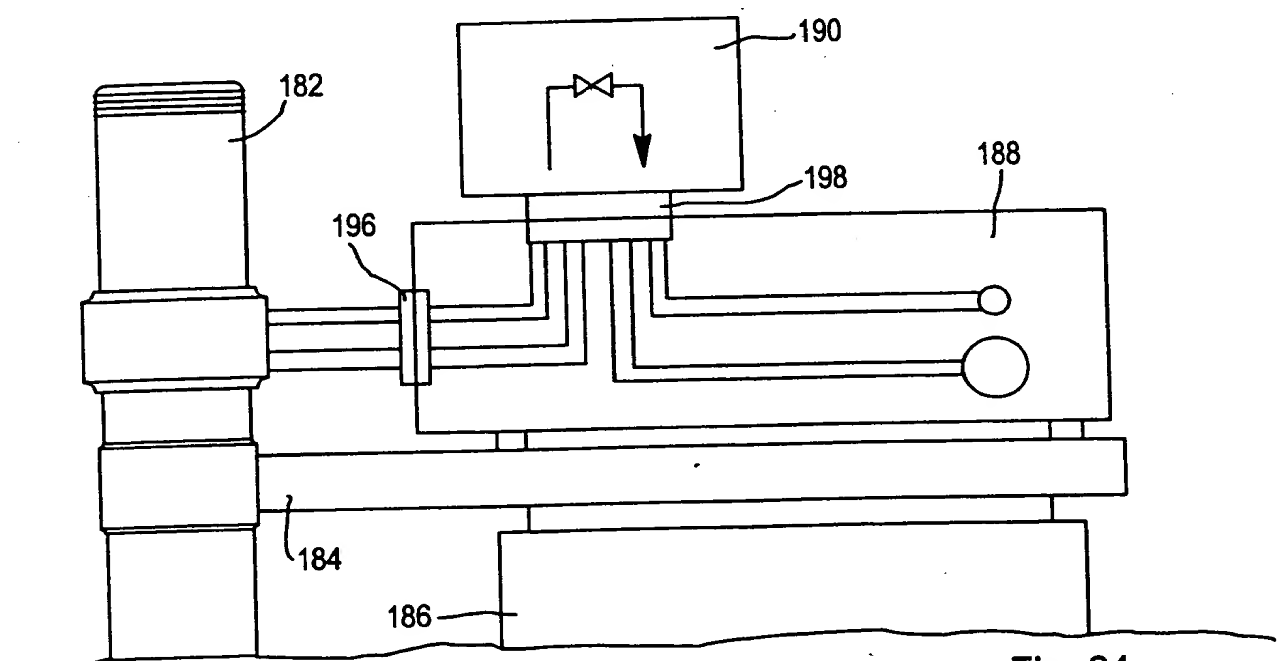
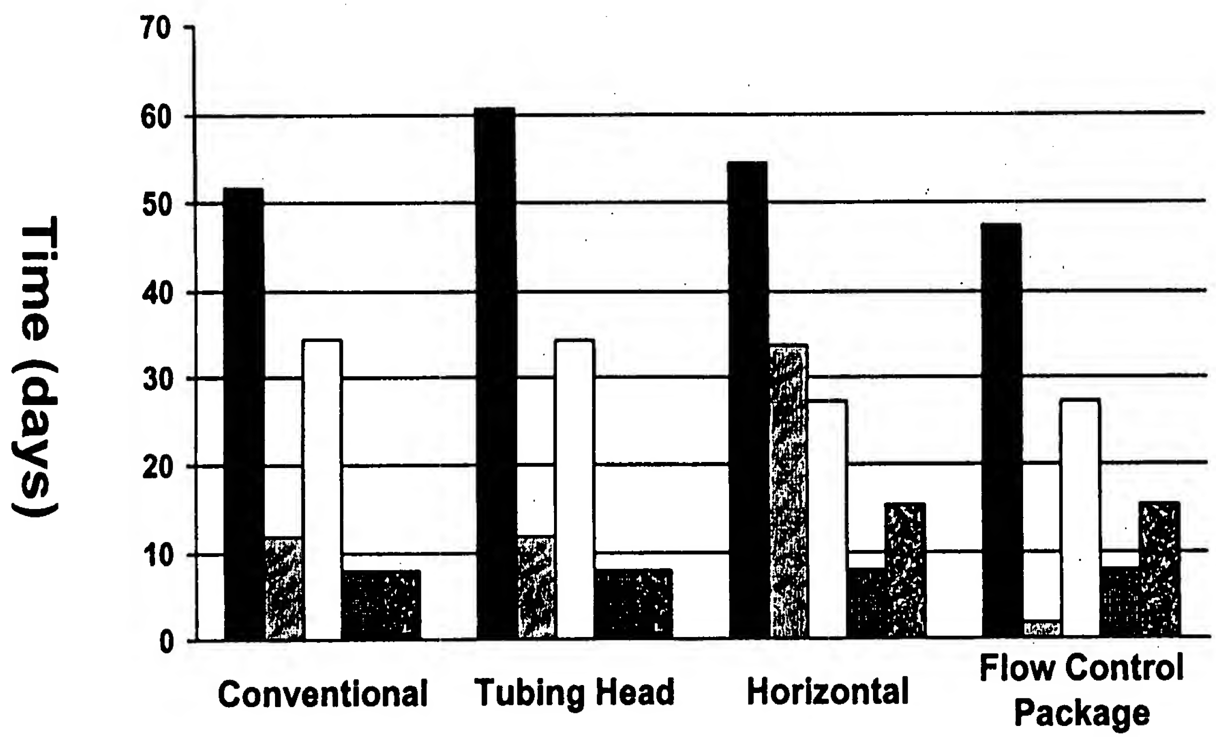


Fig. 21



	Conventional	Tubing Head	Horizontal	Flow Control Package
Installation	51.7	60.7	54.5	47.5
Christmas tree workover	11.9	11.9	33.7	1.8
Tubing workover	34.4	34.3	27.2	27.2
Light intervention	8	8	8	8
Heavy intervention	8	8	15.4	15.4

Fig. 22

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F23 filed 10/2/00
Phillips + Leigh